DIRECT TESTIMONY OF
GREGORY M. LANDER
ON BEHALF OF
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY
DOCKET NO. 2019-3-E

INTRODUCTION

Q. Can you please state your name and employment?

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, West 3 Peabody, MA 01960, and my email address is glander@skippingstone.com.

Q. On whose behalf are you testifying?

A. The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy.

Q. What are your qualifications?

A. I am President of Skipping Stone, LLC ("Skipping Stone").

Q. What is your educational and professional background?

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. Have you filed testimony in regulatory proceedings previously?

A. I have filed testimony in several proceedings including FERC Docket No. RP04-251-000, which was an El Paso Natural Gas Company ("EPNG") proceeding regarding pathing and segmentation. In FERC Docket No. RP08-426-000, (also an EPNG proceeding), I sponsored answering and supplemental answering testimony. I also filed testimony in FERC Docket No. RP10-1398, the first fully litigated EPNG Rate case in more than three decades. In addition, I have filed testimony in Massachusetts Department of Public Utilities Case Nos. 13-157, 15-34, 15-48, 15-39; Maine Public Utilities Commission Case No. 2014-00071; Virginia Corporation Commission Case No. PUR-2017-00051; Missouri Public Service Case GR-2017-0215; GR-2017-0216; and California Public Utilities Commission Cases 17-10-007 and 17-10-008 (Consolidated) Applications of San Diego Gas & Electric (U902M) and Southern California Gas Company (U 338-E) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019; South Carolina Public Service Commission Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E; and, Federal Energy Commission Docket No. ER18-1639, South Carolina Public Service

Commission Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E, South Carolina Public Service Commission Docket 2019-2-E, New York Public Service Commission Case 19-G-0066, AND Virginia State Corporation Commission Case No. PUR-2019-00070. Please refer to Attachment A, which contains a full list of case names and docket numbers as well as my current CV.

DISCUSSION

Q. Your testimony concerns natural gas fuel costs, correct?

A. Correct.

Q. Are there any high level concerns about natural gas markets that you want to start with?

A. Yes. I think it's important to begin by noting that the costs of delivering fuel to natural gas-fired power plants include two distinct costs: (1) the gas itself, which is the commodity price and (2) the transportation costs.

Q. What goes into transportation costs?

A. These costs have three components: (1) a fixed cost (or reservation cost component); (2) the usage cost, and (3) a non-monetary charge which is the pipelines' retainage factor.

Q. What is a retainage factor?

A. In simple terms it means that you are delivered less gas at the delivery point than you paid for because the pipeline retained a percentage of your gas for the fuel to run its compressors. When added together and factored in, these make up the "delivered" cost of gas.

Q. Are there other considerations for transportation costs?

A. Yes. Usage of pipeline contracts varies because a utility – like DEC – does not necessarily use a pipeline contract 100% of the time it could use it. This, in turn, affects the "all-in-cost" of gas delivered on that pipeline. Isolating out the effective capacity cost, the "all-in capacity cost" is determined by dividing the total, annual, reservation cost by the units transported (*i.e.*, used) and adding the total annual usage costs for the units of gas used.

Q. What determines the commodity price?

A. A variety of factors, but the most important element to consider here is that natural gas comes from all over the country and is produced in different production areas. The cost of gas in one production area can, and often does, differ from the cost of gas in a different production area.

Q. What determines the transportation price?

A. Transportation is the cost of using a natural gas pipeline. Each pipeline is priced differently, depending on its size, location, sometimes distance of haul between receipt and delivery locations, age or vintage of the service and type of service.

Q. How do you assess these sources?

A. Normally I group individual supply locations into their respective pricing points (*i.e.*, the points associated with published indices' locations) which would put the various supply locations into the same published index point.

Q. What is an index point?

A. An "index point" is a published price for a specific pooling location, or group of receipt and/or delivery locations.

Q. What is a pooling location?

A. A pooling location, in turn is a virtual location at which parties buying or selling gas on a particular pipeline engage in trades.

Q. You say it's "virtual." How does that work?

A. The way a pooling point works is that parties with supply in the areas specified by the pipeline tell the pipeline that they want to sell an amount of that supply to a buyer, and in turn, the buyer tells the pipeline that they wish to buy the same amount from the seller. The pipeline then transfers this amount from the selling party to the buying party. Once that happens, the buying party either sells the gas again to another party at the pool, or puts the gas onto a transportation contract in order to move the gas to another location on the pipeline. On the east coast, the primary pipeline is the Transco pipeline, which is itself divided into different zones, each with its own pricing.

Q. Tell us more about the zones.

A. The Transco pipeline is the main artery of all natural gas on the East Coast. It runs from the Gulf of Mexico to New York. This map at Figure 1 shows the Transco pipeline and the relevant zones I'm discussing.

Figure 1

Source: http://www.1line.williams.com/Transco/files/presentations/2012ExecCustMeet.pdf (Zone labels and dividing lines added by Skipping Stone for clarity).

Q. Why are these zones relevant?

A. Electric utilities have an obligation to serve their customers reliably at the lowest reasonable cost. When an electric utility – like DEC – burns natural gas to generate some of that electricity, the utility must make its best efforts to procure the lowest cost gas. That total gas cost includes the commodity prices, which differ among the different pricing locations and among the different zones.

Q. Is commodity price the most important factor?

A. No.

Q. But if a utility can buy gas at Point A or Point B and the gas at Point A is 25% less expensive than the gas at Point B, shouldn't' the utility always buy the Point A gas?

A. Not necessarily. It depends on the differences between transportation costs.

Q. What do you mean?

A. In the scenario you described, there are cost savings in buying gas from Point A relative to Point B. But it is also possible that the "all-in transportation costs" of holding the rights for transporting gas from Point A are so much greater than transporting from Point B that the "delivered" cost, the "all-in cost" (which includes the gas commodity cost)of Point A gas is higher than the "delivered" price of Point B gas.

Q. You're talking in abstractions. Can we put that into a real-world context? What does Figure 2 show?

A. Figure 2 shows the average seasonal prices at relevant pricing points (Index Points) for DEC.

Figure 2

Seasonal Periods	Days in Period	Southern Natural Avg Price	Transco Zone 4 Avg Price	Transco Zone 5 Avg Price	Transco Zone 5 North Avg Price	Transco Zone 5 South Avg Price	Dominion South Avg Price	Transco -Leidy Line Avg Price
Shoulders 2017	122	$2.960	$2.960	$3.010	$2.960	$3.030	$1.740	$1.715
Shoulders 2018	122	$2.835	$2.855	$2.975	$2.955	$2.970	$2.350	$2.080
Winter 2017/2018	151	$2.760	$2.780	$3.090	$3.075	$3.095	$2.425	$2.375
Winter 2018/2019 thru 3/9	151	$3.143	$3.138	$3.660	$3.665	$3.653	$3.015	$3.100
Summer 2017	92	$2.870	$2.900	$2.950	$2.895	$2.980	$1.850	$1.810
Summer 2018	92	$2.870	$2.890	$2.980	$3.000	$2.990	$2.430	$2.350

Source: Natural Gas Intelligence; Analysis Skipping Stone.

Q. What do we learn from this table?

A. This table shows three important facts. First, the prices in Zone 5 North do not differ from the prices in Southern Zone 5 (Zone 5 South) very often (shown in the lightly shaded cells). Second, when they do differ, sometimes Transco Zone 5 North is lower priced than Transco Zone 5 South, and sometimes it's the reverse. That said, in recent years, Transco Zone 5 South tends to be higher priced than Transco Zone 5 North, but the average price in Transco Zone 5 South is now trending below that of Transco Zone 5 North. Third, between 2017 and 2018, the differences between Zone 5 South and Zone 5 North have shrunk.[1]

Q. This table is a little confusing since it shows three Transco Zone 5 pricing points: (1) Transco Zone 5 South, (2) Transco Zone 5 North, and (3) Transco Zone 5 (*i.e.*, neither designated as North or South). Can you explain this and identify the areas of Transco that correspond to these different pricing locations?

A. Yes. Transco has one "pooling point" in each of its six tariff Zones where it permits pool to pool (*i.e.*, party to party) trades. In tariff Zone 5, that "pooling point" is associated with Transco Station 165. Trades at this location set the published Transco Zone 5 pricing (or index) point.

Q. Ok. That's Transco Zone 5. What about Transco Zone 5 North?

A. Trades that are made on a delivered basis to locations on the Transco system ***north*** of that point (up to the northern end of Transco 5 – and approximate to Transco Station 185) are reported as Transco Zone 5 North sales.

Q. What is a "trade on a delivered basis"?

A. It means that the buyer is buying the gas at a location where it will use the gas or transport the gas from the purchase location to their use location.

[1] For the Winter of 2018/2019, the data is only through March 9, 2019 owing to the date this testimony is due.

Q. And Transco Zone 5 South?

A. Trades that are made on a delivered basis to locations on the Transco system ***south*** of Transco Station 165 (down to the southern end of Transco 5 – proximate to the GA/SC border, Elba Express and between Transco Station 130 and Transco Station 135) are registered/reported in the trade press as Transco Zone 5 South priced sales.[2] Since July of 2016 a large trade publication, Natural Gas Intelligence (NGI), has published prices for all three Zone 5 pricing points.[3]

Q. So, Transco Zone 5 is "pool to pool," while Transco Zone 5 North and Transco Zone 5 South are "delivered"?

A. Correct.

Q. Is there any significance to the fact that NGI has published these three pricing points since July of 2016 and yet there is only one Transco "Pooling point" in Zone 5?

A. Yes. It means that the three pricing locations are liquid,[4] in that there are numerous trades each day corresponding to each location that are reported to NGI.[5]

[2] The way gas trading on Transco works, gas can be traded at any location. When it is traded at a pool the transfer is party to party. When it is traded at another location the delivering party (seller) identifies themselves and the contract out of which the gas goes to the buyer (receiving party). Once received by the buyer, that party can put the gas onto a contract on Transco and take that gas to locations covered by their contract. The only real difference is that the parties respective contracts have to be identified to Transco for these "other location" trades, whereas at pools only the respective parties need to be identified to Transco; and the trading parties need not divulge to one another their contract information.

[3] The Platts publication, Gas Daily also reports prices for these three individual pricing points.

[4] The relevance of this "liquidity" aspect will become evident when I make recommendations below.

[5] Since July 1, 2016, there was one day that NGI published no price for Transco Zone 5 North. That was September 1, 2017. NGI published a price for each of Transco Zone 5 South and Transco Zone 5 on every price publishing day since NGI commenced reporting prices for Transco Zone 5 South trades.

Q. What does "delivered basis" mean?

A. "Delivered basis" means a utility is buying gas at locations where it either burns the gas or at a location from which the utility has pipeline capacity to move the gas from the purchase point to the use point. Finally, "delivered gas", from the perspective of the seller, means that they are selling the gas at a point that can act as a delivery point out of the pipeline they are transporting the gas on.

Q. So a utility like DEC has contracts on multiple pipelines?

A. Correct**.**

Q. And using those different pipeline contracts, DEC can buy gas at various locations to ensure its buying the lowest cost "delivered" gas for its customers at any given time?

A. Correct.

Q. But doesn't that mean that sometimes DEC isn't using some of its capacity contracts because gas delivered on that contract is more expensive?

A. Yes.

Q. In that scenario, what should a utility do with its unused capacity?

A. A utility like DEC has three options. First, it can do nothing and let the unused capacity sit fallow.

Q. Do ratepayers still pay for that capacity if it's unneeded and fallow?

A. Yes they do, which is why that's the worst option.

Q. What else could they do?

A. Second, the utility could buy gas at one location and use the capacity contract to move the gas to a second location. The utility could then sell the gas at the second location at a profit, and then credit the proceeds from the transaction back to customers to reduce the cost of the capacity. This is called a "third party sale."

Q. And third?

A. Third, the utility can release capacity (i.e., its rights to use a portion of its capacity) into the secondary market, which allows a third party to use the released capacity that they acquire in whatever way the third party wants.

Q. Which is better, third party sales or capacity releases?

A. It depends, but there are ways to analyze the markets over time to create best management practices, which I will discuss later.

Q. So, presumably there are times when DEC has unused capacity. What does DEC do with its unused capacity?

A. This was a topic I was hoping to analyze in this proceeding so that I could evaluate whether DEC is doing the best job possible of reducing ratepayer costs.

Q. So you don't have an opinion?

A. Well, my opinion is the utility is not sufficiently monitoring its own operations to make any informed analysis of its operations. To evaluate how well a utility monetizes its unused capacity, you have to know how it uses its pipeline capacity portfolio on a daily – and possibly even hourly – basis. We asked for that hourly data, and DEC says it not only does not report such data, it stated that it does not even report ***daily*** data.[6] I asked for hourly because from that data, I could derive daily usage vis-a-vis contracted daily capacity as well as identify potential for partial daily releases under which capacity is released on an intraday (*i.e.*, within day) basis.

[6] *See* Duke Energy Carolinas, LLC's Response To South Carolina Coastal Conservation League And Southern Alliance For Clean Energy's First Request For Production Of Documents, Response to Request No, 6 (attached as Attachment B).

Q. Is that lack of data surprising?

A. Very. Either the utility has the data and has not produced it to us because they are not required to "report" it, or they simply do not have it. Either way, neither we, ORS, nor the Commission have adequate insight into how DEC manages its unused capacity to reduce ratepayer costs.

Q. But DEC gave you monthly data. Isn't that enough?

A. Not remotely.

Q. So what should DEC do?

A. First, DEC should clarify for the Commission whether it does or does not currently have this hourly usage and load data. If it does, the Commission should require DEC to report and disclose it. If DEC does ***not*** have this information, the Commission should require DEC to begin tracking it immediately.

Q. What would you do with this data?

A. Once you have the information, you can analyze how well the Company monetizes its unused capacity on an hourly basis. You can also implement practices to determine whether third party sales or capacity releases are best for the ratepayer.

Q. How?

A. By benchmarking third-party sales.

Q. How do you do that?

A. First you calculate, by pipeline, a daily Weighted Average Cost of Gas (WACOG), plus a Weighted Average Fuel Loss percentage (WAFL%), plus a Weighted Average Transport Usage Cost (WATUC) to arrive at a Daily Delivered Gas Cost (DDGC). Then, using either a Weighted Average Sales Price (WASP) or individual sales price (ISP) of deals, the Company can calculate the "margin" on those third-party sales. In this way, margin equals WASP (or ISP) minus DDGC.

Q. So, in other words, the Company would calculate the average profit it makes on third party sales?

A. Correct.

Q. What would the Company do with that information?

A. Again, the goal is to ensure no pipeline capacity lies fallow because that's capacity ratepayers pay for yet for which they receive no value. The Company would use this "average profit" information to guide its choice between third party sales and capacity releases for unneeded capacity.

Q. How so?

A. By using the average profit margin on third party sales to set a reserve price for capacity releases. This ensures that the Company will earn at least as much in capacity release as it does on third party sales.

Q. How does that work?

A. In the day-ahead capacity release market, that market "clears", (*i.e.*, awards of released capacity are made) prior to the nomination deadline for day-ahead transactions. This means that fully-open, as well as pre-arranged, biddable deals "close" in time for the acquiring shipper to employ that capacity the following day. Using the calculated margin from previous third-party sales to set the reserve price (again where appropriate), the Company can readily ascertain the typical contribution to fixed costs from these third-party sales (*i.e.*, this is the same contribution that capacity release revenue per Dthd released provides) and can use this as a guide to setting a reserve price for offered capacity when the two opportunities are present.

Q. What is the benefit of establishing a reserve price?

A. Again, it ensures that the Company will earn at least as much in capacity release as it does on third party sales.

Q. But what if the Company identifies unneeded capacity but thinks that it might actually end up needing it? Should the Company just hold on to it even if ratepayers have to pay for it?

A. No. Capacity should never lie fallow because it provides ratepayers no value even though they have to pay for it.

Q. But won't DEC argue that the fallow capacity *does* provide ratepayer value because DEC might need that capacity to respond to an unexpected demand and DEC's ability to call on it at the last minute is valuable?

A. There is ratepayer value to that kind of nimble flexibility, but you can still quantify it and ensure ratepayers get the full monetary value.

Q. How would you maintain flexibility while getting full monetary value?

A. If the Company isn't 100% certain it does not need capacity, it can offer to release it on a recallable basis. While the rate it can receive for recallable capacity is obviously lower than for a complete release, it can still earn some revenue from the capacity to offset ratepayer costs. This allows the utility to preserve flexibility (which has ratepayer value) while receiving compensation for the unused capacity (which also obviously has value).

Q. So a utility would offer recallable capacity at a discount?

A. Yes.

Q. So how would you quantify the value of flexibility?

A. As we just discussed, releasing capacity on a recallable basis involves a likely discount. In other words, the utility is willing to accept less revenue for its capacity in order to preserve flexibility. It gives up revenue but preserves flexibility in equal measure. That discount, then, is the "value" the utility assigns to the flexibility.

RECOMMENDATIONS

Q. So, what are your recommendations?

A. First, the Commission should ensure DEC tracks and reports all gas consumption at all generation units on an hourly basis so that we can begin to evaluate whether DEC is optimizing its unused capacity. Second, to the extent DEC does not already do this, the Commission should require DEC to track the margins on third party sales that use capacity unneeded for planned generation so that DEC can then use those margins to set a reserve price on capacity releases. This ensures ratepayers get the best value for capacity that DEC does not need to generate electricity. To the extent DEC needs to preserve flexibility on its system, it can offer the capacity it *may* need (as opposed to that capacity that it knows *it will not need* based on season, weather and demand) on a recallable basis at a likely discount. The buyer's offer price below the reserve margin (for the capacity it *knows* it will not need) represents the value assigned to that flexibility.

Q. Does that conclude your testimony?

A. It does.

Attachment

A

SkippingStone

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.

- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.

- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.

- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open

Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 “California Energy Crisis” and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Provided market entry assessment for large international manufacturing and service company seeking to enter U.S. micro-grid, combined heat and power, and integrated solar, gas & battery markets.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients’ attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, intellectual property rights cases, and supply contract proceedings as both up-front and behind the scenes expert.

Associations and Affiliations:

Longest serving Member of Board of Directors for NAESB and prior to that GISB – 23 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

Attachment B

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-3-E

IN RE:

Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC	)	**DUKE ENERGY CAROLINAS, LLC'S RESPONSE TO SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS**

Duke Energy Carolinas, LLC ("DEC" or the "Company"), by and through counsel, pursuant to Rules 103-833(C) and 103-835 of the Rules of Practice and Procedure of the South Carolina Public Service Commission and the South Carolina Rules of Civil Procedure, hereby responds to Intervenor, South Carolina Coastal Conservation League and Southern Alliance for Clean Energy's (collectively, "CCL/SACE") First Request for Production of Documents as follows:

RESPONSES TO FIRST REQUEST FOR PRODUCTION OF DOCUMENTS

1. Please provide copies of any responses to data requests by any other parties in this docket. Where available, please provide copies electronically in the native file format.

RESPONSE: Responsive documents are produced herewith and have been uploaded to a FTP site. DEC will continue to follow up with any additional discovery responses as they are available.

2. Based upon forecasted load projections, please provide duration curves for annual forecasted megawatt-hour per day production alongside gas consumption (in dekatherms per day) for the forecast period.

RESPONSE: DR 1-2 requests information that is not within the Company's possession as it relates to duration curves for annual forecasted megawatt-hour per day production. Please see response to DR 1-3 for forecasted natural gas consumption during the fuel proceeding billing period (10/1/19 - 9/30/20).

3. Please provide the Company’s near- and long-term natural gas consumption forecasts, as well as any of the inputs and worksheets not explicitly stated in the forecasts.

RESPONSE: Please see the attached Excel spreadsheet for the monthly natural gas burn projections by station for the billing period (10/1/19 - 9/30/20) of the current fuel proceeding. All projections are subject to change based on many factors including, but not limited to: changes in delivered natural gas prices versus the average delivered cost, weather driven demand, and station outages. Long-term gas consumption forecasts beyond June 2020 are not being provided as such information is outside the scope of this proceeding. The requested additional data behind the model results is not being provided because it contains confidential and proprietary information that Company is not permitted to share with third parties.

2019 DEC SC
CCL_SACE DR 1-3 Pr(

4. Please provide projected annual fuel consumption, and heat rate and megawatts of capacity for each of the Company’s gas-fired units, as well as for each unit that has been converted to dual-fuel technology that enables it to burn coal, gas or a mixture of gas and coal.

RESPONSE: Please see the attached spreadsheet with the projected monthly fuel consumption, heat rate and capacity factor for the Company's gas-fired units, including those converted to duel-fuel technology, for the billing period (10/1/19 - 9/30/20) of the current fuel proceeding.

2019 DEC CCL_SACE DR 1-4 Monthly Gas

5. Identify all natural gas pipeline transportation capacity contracts (intrastate and interstate) held by the Company for the current period. For each contract, please provide the following:

a. Signing parties
b. Pipeline name
c. Contract ID
d. Type of contract
e. Daily entitlement
f. Primary receipt location(s)
g. Primary delivery location(s)
h. Market area(s)/Zones covered by primary path
i. Current term
j. Expiration date
k. Price (the actual prices, not just whether the price is a tariff rate or a negotiated rate and please separate reservation rate (daily) from usage rate)
l. Power plant(s) served

CONFIDENTIAL RESPONSE: Please see attached CONFIDENTAL attachment.

2019 DEC SC CCL_SACE DR 1-6 CC

6. Please provide the Company's MW production and fuel use by hour by day for each of the Company's generating facilities capable of using gas for the current period and for gas used, please include the pipeline and Contract ID(s) used to deliver such gas.

RESPONSE: See attached 2019 CCL SACE DR1-6 Monthly Gas Deliveries by Station 060118_053119 for the monthly natural gas receipts in MBTUs by station and pipeline for the test period along with the associated monthly net generation in MWh. The Company does not report gas deliveries and generation by day.

2019 DEC CCL_SACE
DR1-6 Monthly Gas

7. Please provide copies of any precedent agreements for natural gas transportation services entered into by DEC or by any of its affiliates on behalf of DEC, any amendments thereto, and any negotiated rates (and please separate reservation rate (daily) from usage rate)

RESPONSE: The agreements requested contain confidentiality provisions that restrict DEC from disclosing the agreements to a third party, and accordingly, cannot be provided.

***** DEC reserves the right to supplement its responses to these requests should additional responsive documents be identified. *****

[Signature on Following Page]

Dated this 29th day of July 2019.

s/Samuel J. Wellborn
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STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2019-3-E

In re: Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC	)	CERTIFICATE OF SERVICE

I certify that the following persons have been served with one (1) copy of the Direct Testimony of Gregory M. Lander by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

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/s/ Emily E. Selden

August 20, 2019